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COMMONWEALTH OF MASSACHUSETTS
BEFORE THE
DEPARTMENT OF PUBLIC UTILITIES

Notice of Inquiry/Rulemaking Establishing Procedures for Electric Industry Restructuring	))))))	**DPU 96-100**

Comments of
Boston Edison Company

I. EXECUTIVE SUMMARY

The proposed rules issued by the Department of Public Utilities on May 1, 1996 represent a constructive and well thought out approach to introducing competition into the electric utility industry. The Department deserves a great deal of credit for advancing the process. While we believe some elements of the Department's approach require modification, the Department has plainly provided a sound base from which to work.

These comments do not address every issue raised in the proposed rules. Rather, as suggested by the Department, we have focused on significant issues of fairness or workability in the draft rules. It should be noted that the overriding consideration in our comments is the impact of restructuring on our customers. While our goal is to find and take the quickest path to customer choice, it must be done in a way that results in our customers being better off after restructuring than before. Within that context, our key conclusions are as follows:

Customer Focus - The Department rightly concludes that the impact that restructuring will have on customers must be the guiding principle throughout this process. We think customer impact may not be sufficiently taken into account in the Department's order.

First, there must be a recognition that the majority of utility customers use relatively small amounts of power and probably place a very high value on simplicity and continuity. Care must be taken that the new structure does not make these frequent, small transactions overly complex.

Second, the Department should and must take this opportunity to look not just at the newly competitive generation sector, but at the utility business as a whole. Customers, after all, will see both the competitive generation and regulated distribution parts of the business. Both must work together. We see this time as a unique opportunity to simplify the distribution system business. For example, distribution charges should reflect the distribution business characteristics rather than those of the bundled business that historically provided service. It may be that the model of the cable television or the telephone industry will be useful, where the customer pays a simple, monthly fixed charge for access to the network, and there is relatively little reliance on consumption-based charges.

Second, the Department's order suggests that Basic Service - that is, the energy service that the Distribution Company would supply to customers who do not elect a specific energy supplier - should be based on the spot market price of energy. In effect, on day 1 of choice, all customers would be involuntarily transferred to a spot market rate. We believe that customers do not want to undergo a forced change of this nature in the character of their service. They do not want to find their stable and simple service replaced by one that is unknown in character and is potentially highly variable in price. The Department's restructuring plan needs to accommodate not only those customers that want to choose, but also those customers who want to continue to receive the kind of service they receive from their local utility today. Basic Service to customers should be of similar character to service presently received, until a customer elects otherwise.

Market Structure - We are in general agreement with the Department's proposed market structure, although our view of the optimal structure differs in some ways from that of the Department. We strongly support the creation of a visible market clearing price and an Independent System Operator (ISO). We also agree that the governance of these structures needs to be changed from that which exists presently in NEPOOL, and we concur that the most sensible way of forming these entities is to build on the existing NEPOOL organization. We agree with the movement toward the creation of a central spot market and urge this process to continue; but we are concerned with the Department's apparent conclusion that such a complex institution can be created by the beginning of 1998. We believe the parties must work together to develop a schedule that is aggressive, but realistic.

Divestiture and Corporate Structure - The Department finds, and we agree, that utilities' competitive generation and marketing functions need to be functionally separated from their regulated delivery functions. However, to accomplish this separation, the Department expresses a strong preference for divestiture of generation assets, and requires that at a minimum all utilities adopt holding company structures in which each business function is housed in a separate corporate entity.

With respect to the Department's incentives and penalties relating to divestiture, we have several concerns. First, we believe there is a substantial value in allowing individual market participants to determine their own optimal business structures, and this perspective is absent from the Department's proposed rules. Second, it is not clear that continued electric utility ownership or affiliation with generation has been shown to cause problems that are commensurate with the very substantial penalties for non-divestiture contemplated by the Department. Third, the Department's approach relies on penalties (very harsh penalties, under the Department's rules) rather than incentives, in order to accomplish an objective which may not even be within the Department's authority. Fourth, it is unclear why substantially all of the Department's objectives could not be achieved with a requirement that some, but not all, generation be divested. Fifth, although the rules appear to contemplate that a utility will benefit from a more favorable cost recovery if it divests, the terms of the benefit are so vaguely defined as to deprive the rules of any incentive effect. Finally, the Department's suggestion that divestiture be accompanied by a 10 year buy back power contract essentially eliminates the market valuation benefit of divesting.

With respect to corporate separation, we believe such a requirement would create cost and complexity out of proportion to the small benefit that it would provide, beyond that which could be achieved simply by implementing corporate codes of conduct and procedural guidelines and by following the other provisions of FERC's recently completed open access rulemaking. For integrated utilities like Boston Edison, corporate restructuring would necessitate costly and time consuming renegotiation or restructuring of multiple agreements, obligations and permissions.

Stranded Cost Methodology - The Department's order suggests that in the absence of voluntary divestiture by a utility, an administrative valuation method should be used to determine stranded costs. This involves forecasting operating costs and market prices for more than 10 years into the future. Given the exceptionally large differences of opinion held by various parties on the forecasts of these elements, the high probability that such differences will remain unresolved, and the very wide deadband for reconciling forecast data to actual that is proposed by the Department, we have serious doubts about the viability of this approach.

These problems can be dealt with very effectively through the use of a Standard Offer approach to stranded cost valuation. We feel that the Department and other parties may in the past have misunderstood this approach and have elevated a number of concerns that can be adequately addressed or dealt with within this framework. As we and others have described previously, under a Standard Offer approach all sunk costs are recovered through the access charge and in return all customers are offered a guaranteed price for Basic Service during the transition period. In our comments today we describe how our Standard Offer methodology would work and address the concerns other parties and the Department have raised with such an approach. We believe our standard offer proposal accomplishes the following:

- It avoids the need for the Department to engage in a contentious and potentially unworkable 10 year forecast of market prices;
- It automatically prevents customers from being "overcharged" for stranded costs;
- It is extremely compatible with customer choice;
- It can be structured to permit customers to choose other energy suppliers while retaining the standard offer benefits;

- It guarantees that non-choosing customers continue to receive energy service of the same character and quality as provided historically;
- It assures that utility generation is subject to competitive market forces;
- It is completely compatible with the development of a spot market.

Whether or not the Department adopts our proposal as its preferred approach, we believe the rules as finally adopted should not be overly restrictive in this area. It is important that parties to a utility's restructuring case have the latitude to negotiate Standard Offer mechanisms for stranded cost recovery if they have a common interest in doing so.

Above Market Purchased Power Costs - The Department proposes and we agree that the above market costs of non-utility generator (NUG) power contracts are eligible for stranded cost recovery. However, we have two concerns. First, the Department suggests that above market NUG costs expected to be incurred after the 10 year transition period would have to be recovered during the transition period, without raising rates. This requirement is not feasible. The costs in question for Boston Edison may be over half a billion dollars, the recovery of which would effectively be precluded if a limitation of this sort were enacted. Second, the Department suggests that utilities must do all they can to mitigate purchased power costs. To effectuate this mandate, mechanisms are needed to incent renegotiation of power contracts to reduce future charges that are far above expected market prices. The restructuring standard applied to utility stranded cost is that sunk costs may be subject to recovery, but costs incurred in the future should be disciplined by the market. Power contracts should be treated symmetrically.

Nuclear Decommissioning Costs - The Department proposes to permit recovery of the decommissioning costs that will necessarily be incurred when nuclear plants shut down. However, the Department appears to contemplate that such recovery will stop - or that the amount of the obligation will be fixed - as of the date the nuclear plant ceases operation. Since it is clear that decommissioning activities will be undertaken for many years after plant shutdown and that the ultimate costs will not be known until the conclusion of that effort, this limitation would subject the utility distribution company to enormous risk. Such a result is neither workable nor fair and also raises signifcant questions from the standpoint of the Nuclear Regulatory Commission.

Recommendations For Continued Progress - Where do we go from here in order to continue to make progress towards industry restructuring? We strongly believe that significant progress has been made on virtually all fronts over the past year. The largest area of progress we see is in the development of understanding by electric utilities, the Department and other participants to this process of the many changes, interrelationships and working details that are involved in industry restructuring. The one area that continues to lag is that of customer involvement and input. We expect and encourage significant input in this area during the next year, particularly when customers begin to see unbundled rates and market based energy prices. Other areas such as market restructuring are well underway, particularly given the recent completion of FERC rulemakings in this area. Other elements of market reform such as the reform of NEPOOL and the development of an ISO are also taking place, albeit not as fast as some would like.

We have two primary messages in these comments. One is that we should continue to make progress, by remaining flexible and not forcing premature commitments to positions that cannot be adhered to. These include rules regarding market structure that are outside the Department's jurisdiction, or which require regional approaches, and rules regarding corporate structure and divestiture that confine rather than enhance the choices of market participants. These also include rules regarding stranded cost recovery that can only be viewed as confiscatory. We believe that flexibility will lead to settlements, whereas some proposed rules may only lead to litigation. The second message is to remain focused on the customers. Rules relating to basic service and distribution service require customer input that has not yet been received.

We look forward to continue to work with the Department, customers and all affected parties as we continue to move down this road to industry restructuring.

II. MARKET AND CORPORATE STRUCTURES

In Part III of its May 1 Statement, the Department set out its vision of the future electric market structure which it believes will best achieve its goals in a manner that is consistent with the restructuring principles established in DPU 95-30. Generally, the Department addresses two distinct areas of concern: the structure of the regional power market and the structure of the individual entities that will participate in that market. Boston Edison finds that the Department's vision of the future electric marketplace has several characteristics which are similar to its own. Even with this shared vision of the future, there are several issues raised by the Department with which we do not agree. We offer our comments on these issues below.

A. Market Structure Issues

As stated above, we find ourselves in general agreement with the Department on market structure issues. For example, we agree that operation of the transmission system should be conducted by an entity substantially independent from market participants. Further, we acknowledge that the governance structure for such an entity needs to be designed so it supports a robust, non-discriminatory, competitive electric power market. We are a strong advocate for a transparent market price, as evidenced by our E-Plan proposal and our current activities to develop and publish a regional Market Price Index. We also completely agree that modifying the existing NEPOOL structure is the quickest way to develop a competitive market.[1]

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[1] This evolutionary process is working. At the April 1996 NEPOOL Executive Committee meeting there was a consensus to accelerate NEPOOL Plus so that it can be filed later this year. More recently, on May 3, the NEPOOL Executive Committee voted unanimously to form an ISO and commissioned a task force to develop by year-end a detailed proposal to accomplish the following:

1. Transform the NEPOOL functions and infrastructure at the NEPOOL Dispatch Center into an ISO.
2. Create a structure in which the ISO employees are independent from any of the NEPOOL Participants.
3. Create an independent governance board for the ISO that will not be controlled by a single participant or class of participants.
4. Allow the ISO to control the operations of the transmission system, generation dispatch, and the implementation and administration as appropriate of market settlement rules and regional transmission tariffs in an open and non-discriminatory manner, in accordance with current and future NERC and NPCC requirements.
5. Capture the benefits of economy and reliability contemplated by NEPOOL Plus.

We note two areas of concern with the Department's discussion of market structure. The first relates to schedule. The Department appears to propose that a spot market based pool could and should be in place by the by the beginning of 1998. While this is an appropriate direction, we believe such a schedule is not practical. To create such a complex structure will require that the market participants reach an agreement in principle, followed by full development and implementation of the structure and rules to support operation of the pool. By comparison, the smaller task of completing and receiving FERC approval of an amendment to the NEPOOL Agreement to reflect the changes envisioned by NEPOOL Plus will in all likelihood take until mid-1997. To expect the spot market to be in place only 6 months later is unrealistic.

The second area of concern relates to the Department's suggestion that
it sees no compelling reasons why the merchant functions of the Power Exchange (PE) should be combined with the reliability function of the ISO. The Department believes separation of the two can avoid problems that arise related to market power and affiliate transactions, and may avoid disputes over dispatch order decisions of the ISO. We do not agree with this position.

The separation of the ISO from the PE is a debate that is occurring across the country. The issues are well known and have been argued at length. In New England, they will ultimately be resolved in the context of NEPOOL reform and related FERC proceedings. However, to the extent the Department will be involved in these determinations, we believe it should not take the position outlined in DPU 96-100. We believe that the dispatch of the generation system and the operation of the transmission system are an integral whole that should not be separated. The ISO should do both. The necessity of this structure has been set out very well by Professor William Hogan in various articles and publications, including a December 1995 article in *The Electricity Journal*. Professor Hogan concludes the following:

> This is a seriously flawed idea. No commercial or technical case can be made for separating operation of a spot market into distinct PE and ISO

We believe the transformation of NEPOOL into an ISO is a positive step that will go a long way toward achieving fair competition and ameliorating concerns about vertical market power.

> functions. There are, by contrast, very compelling reasons for keeping these functions together. These reasons explain *why there is no competitive electricity market in the world* where an ISO has been separated from the function of providing a bid-based economic dispatch. Indeed, when the extreme suggestion to sharply curtail the functions of the ISO by precluding any bidding information is described to individuals familiar with power systems operations - apart from proponents of the separation fallacy - the response is one of disbelief. (Page 27.) (emphasis in original)[2]

He goes on to note that it is only with the combination of the ISO and PE functions that the most efficient economic decisions are made without discriminating between pool transactions or bilateral transactions. The vague and, in our view, unsubstantiated concerns about potential disputes over ISO actions do not warrant jeopardizing the economic benefits offered by central dispatch.

The issue of the integrated nature of the transmission system and the generation system will need to be completely addressed in the context of the full development of an ISO proposal. The current supportive relationship between transmission and generation must be managed to assure system reliability. In general, it is not practical to assume the ISO could dispatch generation solely on the nominated dispatch schedules of the market participants. The generation dispatch will be constrained at times by the transfer limitations of the existing transmision system. In addition, the generation dispatch would be constrained by the transfer limitations of the existing transmission system. Those limitations could be very significant in instances where major changes in the generation pattern develop imposing stresses on the system well beyond the criteria under which the integrated electric system was developed.

B. Corporate Structure Issues

We agree with the Department that utilities need to functionally separate their competitive generation and marketing functions from their regulated delivery functions. However, for the reasons set out below we think the Department's proposed "incentive" structure

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[2] Some of the compelling reasons for keeping these functions together relate to the role of economic dispatch in meeting transmission constraints and maintaining balance within the transmission grid. They also relate to the efficient pricing mechanism that recognizes the need to consider the operation of the grid and the short-term costs of congestion on the grid.

for divestiture is flawed. We also think the Department's requirement that utilities reorganize themselves into holding companies with separate corporate entities performing each of these activities is not workable.

At the core of the problem is the Department's mandate of a single type of corporate structure for all utilities, which we think is unnecessary and bad policy. Rather than adopt a "one size fits all" approach, the Company suggests that the Department not attempt to mandate any particular corporate structure. Instead, the Department should let the market dictate what structure is appropriate for each utility. Once the market structure develops, each participant, including each utility, will decide in which markets to compete and, in parallel, will determine whether functional unbundling, divestiture or some combination of the two puts them in the best competitive position. The Department's rules should allow utilities the same opportunities available to non-regulated entities to choose how they want to organize themselves to compete effectively in the emerging market.

1. Divestiture

Divestiture obviously represents the extreme version of corporate unbundling.[3] We can agree in principle that divestiture might be an appropriate course of action for some market participants, based upon their own business decisions and perceptions. We can also agree in principle that there might be circumstances where evidence of market power might dictate such an outcome. Fundamentally, however, we do not see that the facts as they exist in New England support a case for divestiture. Accordingly, we believe that the Department's proposed "incentive" structure for divestiture is badly out of balance.

In the next section we will discuss more specifically the issue of stranded costs. Our major concern is that the proposed "incentive" for divestiture is in fact an unworkable and punitive penalty which, depending on the penalty percentages adopted, may all but compel

[3] If the Department's intended purpose is to have utilities divest various functions, then corporate restructuring as discussed below will only slow this process down. In order to divest, the restructured holding company would have to go through the entire regulatory and debt restructuring processes again.

divestiture as the outcome. As a legal matter we do not believe that the Department has the authority to mandate divestiture of generation. As a corollary, we do not believe the Department may condition something to which a company is entitled, such as a reasonable opportunity to recover stranded costs, upon a requirement that divestiture take place. Although we believe our interpretation of the law is correct, we recognize clearly that there is a matter of degree in any question of what is reasonable and what is an incentive as opposed to a penalty. Accordingly, we remain open to consider a more reasonable and more balanced set of incentives tied to a more practical and workable approach to divestiture.

As stated previously, we do not believe that a strong case has yet been made that divestiture is required in the current situation. Clearly the current situation is one of moving into and through market transition. We already know that the electric marketplace is going to be vastly different in a few years from what it is today. This will be the case due to forces already underway in the marketplace as well as due to actions by FERC. We believe that sound public and economic policy would suggest that the market, and the individual market participants, should in the first instance determine what business combinations and structures will best serve customers and thrive in this changing market. Although there may certainly be *a priori* concerns regarding market power which can and should be addressed (as for example through the various open access requirements established by FERC, the establishment of an ISO and through functional separation requirements or codes of conduct), there is no evidence yet that market power concerns cannot be successfully dealt with through these mechanisms.

The evidence that is currently in this docket--including the testimony of R. J. Gilbert for Massachusetts Electric Company and the study by Hartman & Tabors submitted by the Attorney General -- suggests that horizontal market power is not really a significant problem in the region, even under the current market structure. We do not believe that there is evidence in this docket regarding vertical market power. Indeed, whatever evidence there is would be of questionable relevance since we really have nothing to draw upon to conclude that functional unbundling and other FERC restructuring requirements will not be successful in mitigating the market power concern. To the contrary, all generally available evidence, drawn from the related market affiliate issues in the natural gas industry and from procedural separation requirements imposed as a condition of corporate mergers, points to the conclusion that divestiture is not a requirement for the existence of a workable competitive market. Our point is not that we should be blind to the issue, but simply that there is not sufficient evidence to outweigh the sound starting principle that market participants should be free to choose their own businesses and business structures. It follows that there is no evidence to support the imposition of a draconian penalty for those who do not choose a particular structure.

To the extent the Department proceeds with a divestiture incentive, it must clarify its rules. The Department must make it clear that if a utility divests, it will be entitled to a clear and beneficial stranded cost recovery treatment. The Department also does not address the question as to whether the party acquiring the divested asset could have any affiliation or relationship with the seller. There is also a question as to whether all of such assets must be divested in order to fit the definition of divestiture. It would seem unlikely that all generation assets could be divested (e.g., nuclear), even if that were desired. Also, if the issue were horizontal market power, it is not clear that 100% divestiture would be required to alleviate the concern. Similarly, if the issue were market valuation, it would seem that less than 100% might help establish the market value, while trying to divest all at once might only serve to swamp the market and distort the value. Finally, the concern about vertical market power is not relevant unless there were dealings among the divisions (e.g., generation owned in another state, or all generation sold into the power exchange). In short, it would seem to us that divestiture is not a matter of black and white, and that any penalty or incentive structure should address the many variants of the issue, and above all must provide a clear picture of the treatment received if a utility divests.

The final issue we would raise with divestiture is from a customer perspective. Fundamentally, we believe that many customers desire a bundled or integrated service. In fact, even the Department recognizes this desire in its proposed regulations for basic service, for billing and other elements of the customer interface, which are assigned to one entity: the distribution company. Also many issues of customer concern (e.g., power quality) involve not simply a matter of an energy sale but integrated elements of power and delivery. A knowledgeable provider of those services is required, including knowledge of how they are integrated to meet a customer's needs. While there are sound competitive reasons for the unbundling of rates and services, we would not be so quick to require that any entity that is experienced and capable of providing an integrated service be dismantled so as to prevent it from doing the one thing that many customers desire.

2. Holding Company Structure

The holding company structure proposed by the Department is unfair and impractical for a vertically integrated utility such as Boston Edison. The process for achieving the holding company status envisioned by the Department is complex, time consuming and expensive. The requirement to form separate corporate subsidiaries will result in substantial transactional costs, will lead to operational redundancies between the various entities, and, depending on the final method selected for accomplishing this transformation, may result in significant refinancing costs.

Specifically, there would be numerous regulatory approvals required to finalize such a transaction. At a minimum, a change in corporate status would require approval from the Department under G.L. c. 164, §§ 17A (approval to invest in a subsidiary), 69 (sale or conveyance of property to a subsidiary), 96 (formation of a holding company).[4] The FERC would have to approve any transfer involving FERC-jurisdictional facilities and would have to approve any changes to wholesale power arrangements resulting from the change in corporate status. The Nuclear Regulatory Commission also will have an interest in the effect of restructuring on Pilgrim regardless of whether there is an actual transfer of license from Boston Edison to some other corporate entity within the holding company structure. Assuming other

[4] While we assume such approvals would be forthcoming given the Department's stated preference for this course of action, the Company would still have to do all the necessary preparation to fulfill its obligations under these statutes. Also, neither the Company nor the Department can limit intervention by parties which may add some additional time, costs and uncertainty to the process.

parties intervene in the NRC proceeding, which we believe is a reasonable assumption especially in light of the NRC's level of interest in the effect of industry restructuring on nuclear power plants, the NRC procedure could be quite lengthy. In addition, there could be the need for approvals by the Securities and Exchange Commission, the Federal Trade Commission, and other state and federal regulatory agencies and commissions. We estimate that the time necessary to prepare and obtain all of the requisite approvals, even without a lengthy proceeding before the NRC, is in the range of eighteen to twenty-four months from the date the Department issues its final rules.

There is, of course, no guarantee that any or all of these regulatory approvals will be granted. The prospect of having the entire industry restructuring going forward premised on events which may not occur could result in a very confusing and wholly unsatisfactory set of circumstances which would be in no one's best interest.

The formation of a holding company also requires the completion of several other transactions, the complexity of which will depend upon the final structure selected by the Company. The Company would have to seek shareholder and, depending on the structure selected, bondholder approvals.[5] In addition, the Company most likely would have to renegotiate, refinance, or restructure certain of its debt obligation. In addition, the Company could be named in costly litigation in the event the debt holders perceive the debt restructuring as being contrary to their interests. Also, there are numerous agencies at the federal, state and local levels of government which would have to approve the transfer of various permits and licenses from Boston Edison to some other entity. We also would have to restructure our employee benefits and may have to renegotiate our labor contracts.

While we have not undertaken a formal study of the costs associated with each of these activities, we believe the transaction costs alone to be in a range of ten to fifteen million dollars. Depending on the particular method used to form a holding company, the refinancing costs could

[5] As part of the proceedings before the Department, we would ask the Department to make certain explicit rulings which would have a direct impact on terms of bondholder approvals.

be significantly higher.[6]

While such costs and effort might be warranted if there was a sound business purpose for proceeding, this is not the case here. The formation of a holding company in the manner contemplated by the Department will do little or nothing to alleviate the Department's concerns regarding self-dealing and preferential treatment. Corporate structure changes do not resolve affiliated transaction issues. The same potential for abuse exists whether the utility is divided into separate corporate entities within a holding company or is functionally unbundled within its existing corporate structure. No matter what structure is adopted, affiliated or business unit transactions and transfer pricing guidelines and oversight audits are necessary. Moreover, once these structures are in place, the additional step of adopting a holding company structure provides little or no incremental benefit. Therefore, instead of focusing on changes in corporate structures, the Department should focus its efforts on developing codes of conduct regarding the sharing of information and personnel and the allocation of costs where functionally disaggregated units are the structure of choice. It is here that the Department may impose reasonable standards of conduct to gain the maximum assurance possible that market abuses do not occur.

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[6] See e.g., Comments of Southern California Edison Company on Corporate Restructuring in California P.U.C. Docket Nos. R.94-04-031 and I.94-04-32 filed March 19, 1996. So. Cal. Edison, a vertically integrated utility, estimates the total costs of forming separate corporate subsidiaries at over $500 million.

III. RECOVERY OF STRANDED COSTS

A. Overview

The Department stated in DPU 95-30, and again in DPU 96-100, that electric companies should have a reasonable opportunity to recover net, non-mitigable stranded costs, and that companies must take all practicable measures to mitigate such costs. Unfortunately, we do not believe the method for recovery of such costs embodied in the Department's proposed rules meets this standard. In fact, the rules as written virtually preclude the opportunity for full recovery. If adopted, this approach in our view would be confiscatory, and hence unfair and unworkable.

In addition we are concerned that portions of the Department's proposed rules may cause serious unintended accounting problems.[7] The result could be drastic and unintended immediate writedowns of assets, even in situations where the Department otherwise intends to allow recovery. As can be seen in the note below, the issues are quite complex and will depend on the specifics of a particular situation. In general, we are concerned that all of the Department's proposed rules that fix stranded cost recovery based on future projections, rather than on actual

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[7] As a public utility operating in the current rate-regulated environment we are subject to certain accounting standards not applicable to other non-regulated entities. Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71) allows us to capitalize certain incurred costs for future recovery when we expect to receive rate recovery of these costs. In order for SFAS 71 to continue to be applicable to us the following three criteria must be met:

(1) Rates for regulated services or products provided to customers must be established by or subject to approval by an independent, third-party regulator;

(2) These regulated rates must be designed to recover the specific costs of providing the regulated services or products; and

(3) There must be a reasonable assumption that rates will be recoverable from customers.

In accordance with SFAS 71, we currently capitalize costs incurred that would otherwise be charged to expense if both of the following criteria are met:

(1) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

(2) Based on available evidence, future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If it is determined that SFAS 71 is no longer applicable and we are no longer likely to recover all of our regulatory assets we would have to write off the regulatory assets in accordance with Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed (footnote contd. on following page)

(footnote cont.) Of (SFAS121). In addition, SFAS 121 could require writedowns of our plant assets for differences between the carrying value of our net utility plant and what we would potentially recover in the future rates.

To provide us and our auditors with the proper level of comfort required to continue present accounting practices and avoid significant, unintended and unacceptable write-offs, the final regulations (including the timing of cost recovery) for the restructured electric utility industry must be developed with consideration of the above criteria.

costs incurred, may create such a problem.

In our comments today, we offer an alternative approach to stranded cost determination which we believe is superior and we urge the Department to consider it. Moreover, whether or not the Department chooses to endorse our suggestions, we believe that it is vitally important that the Department be particularly careful, in whatever ruling it may issue, to allow sufficient flexibility to enable settlements that take into account the significant differences in position of the various electric companies and that will accommodate the differing needs of customers and others affected by industry restructuring. We believe there should be room for a variety of methods of dealing with stranded costs, just as there should be room for diverse marketplace participants and corporate structures.

We discuss below three major areas of concern with the Department's proposed approach to stranded cost recovery. The first concern relates to the Department's proposed use of an administrative mechanism to value stranded costs. We believe that a Standard Offer approach, somewhat modified from the Standard Offer methods previously proposed, has substantial benefits for customers and the Department as a transitional mechanism, and we believe the Department should remain open to proposals and settlements embodying such an approach.

Our other two areas of concern relate to the treatment of above-market power purchase agreements and nuclear decommissioning costs. We are particularly concerned that the recovery of these two elements of stranded costs are required to occur in a constricted time period - ten years in the case of purchased power costs, and the period of the existing nuclear plant license in the case of decommissioning. Such an approach places an untenable pressure on near term rates. The Department’s proposal also creates an unreasonable uncertainty regarding potential under-recovery or over-recovery based upon projections of future market prices (in the case of purchase power contracts) or estimation of decommissioning expenditures that may not finally be completed for another decade or more. We suggest that both of these elements are best addressed through a process of actual cost recovery rather than the limited time period estimate and bandwidth approach in the Department's proposed rules.[8]

B. Proposed Administrative Valuation Mechanism

1. Statement of the Problem

There are essentially three ways to calculate stranded costs. The first is a market method, in which one determines a value for utility assets by offering them for sale on the open market and then compares this market value to book value. The second is an administrative method, in which the DPU forecasts the likely costs associated with utility assets and compares them with a likely forecast of market prices over a defined period - often 10 years - and thereby determines a calculated level of stranded asset value. The third is a standard offer method, which requires neither a market valuation of assets nor an administrative calculation of stranded cost. In the standard offer method, all utility sunk costs are initially treated as stranded and recovered through an access charge, but the utility provides to customers a corresponding energy price guarantee (the "Standard Offer") for the 10 year transition period. The energy price guarantee assures that customers receive any economic benefit of the generating units whose sunk costs are being recovered through the access charge.

The proposed rules issued by the DPU adopt an administrative approach to stranded cost valuation for utilities that do not choose to divest their generation. We have two fundamental concerns with this approach: the process will be unacceptably complex, and there will be tremendous, perhaps irresistible, pressures to underestimate and, therefore, undercollect the true level of stranded costs.

The complexity arises from the nature of the task that the Department will be called upon to undertake. It must compare expected utility generation costs (associated with the utility's generating plants and its power purchase obligations) to expected market revenues, over a future 10 year period. The first of these tasks -- the forecast of utility generation costs -- while exceedingly difficult, is at least conceptually able to be done with some degree of confidence for

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[8] We also have concerns regarding the proposal to reduce stranded cost recovery to incent divestiture, as previously discussed in Section II.B.1 above.

all expenses except fuel expense. The historical data on individual units is readily available and the administrative process will be on familiar ground in projecting operation of existing units.

On the other hand, the projection of market revenues with any degree of confidence is essentially impossible. Market price estimates are subject to considerable uncertainty for any unregulated commodity. On the supply side, future prices depend on the current production capacity, future input cost uncertainty, future technological change, and supply responses to price such as new construction, new entrants, and retirements. On the demand side, future prices depend on economic growth, saturation rates, efficiency of use and demand responses to price based on marginal price signals. For the electric utility industry, the uncertainty of forecasting commodity market prices is compounded by the transition from a regulated to a deregulated market. There is no body of historical data on the "market price" or supply and demand responses to changes in that price. The development of secondary markets (forward and futures contracts) is in its early states and is made more difficult by the physical fact of instantaneous production and use in an electric market. In short, a one-time administrative determination of market prices requires breaking significant new ground with billions of dollars at stake.

The difficulties that will arise in such a proceeding are illustrated by the April 17, 1996 report of the Attorney General's (AG) consultants on stranded cost valuation. In the Base Case of that study, which uses the AG's estimate of market prices, the market value of Boston Edison's non-nuclear generation is projected to be \$1.25 Billion.[9] Using the same assumptions for non-nuclear generation, but substituting the NEES estimate of market prices, the report notes that the market value of Boston Edison's non-nuclear generation falls to \$284 Million.[10] The Company does not endorse either of these projections of market value, which are based on two wildly different estimates of market price, but merely points to the swing in value of almost one billion dollars. The magnitude of this spread in these two estimates is a leading indicator of the

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9 Table 1, Estimation of Market Value, Stranded Investment and Restructuring Gains (for Major Massachusetts Utilities), Resource Insight, Inc.

10 Ibid., Table 7.

likelihood of delay and litigation resulting from any one-time estimate of market prices.

In addition to the complexity inherent in this administrative determination, we are concerned that the structure will almost inevitably lead to an underrecovery of legitimately incurred costs. Any one-time calculation provides an opportunity and incentive to "game" the estimates of market price. We would expect that a utility would have an incentive to project low market prices and thus increase the fixed recovery through the access charge. Conversely, we would expect those championing other interests to have an incentive to project high market prices and thus reduce the access charge. Although a true-up mechanism could mitigate against this temptation to bias the market price estimate, the first-mover advantage goes to the side whose estimate is adopted.

The Department contemplates the use of a true-up (with a deadband) at intervals of two, five and ten years. Although a true up with a deadband could work in concept, the forecast of market prices would need to be truly unbiased and expose utilities and customers to an equal amount of market price risk. Instead, the size of the deadbands proposed by the Department leads to substantial risk of unreconciled differences. Given the deadband width, there will be a strong pressure to bias estimates of market price high and expose utilities to the virtual certainty that projected market revenues will fail to materialize and the true up will be of no avail because it will only extend to the edge of the excessively wide deadband. This concern is reinforced by the Department's suggestion that one incentive for rewarding divestiture might be to narrow the size of the deadband -- a clear signal that utilities may be the parties on the wrong side of the estimate that need to make use of the true-up.

As an alternative to the administrative method described above, we have further developed our proposal for a stranded cost valuation method based on a Standard Offer. We believe our proposal can avoid the problems noted above and still achieve all of the Department's restructuring goals. The balance of this section explains why we believe this to be true. The discussion proceeds in two parts. First, we provide a simple description of the Standard Offer and its benefits. Second, we address previously expressed concerns over

Standard Offer methods, focusing in particular on the concerns (which we believe misplaced) that the Standard Offer exempts utility generation from competitive pressures and prevents effective customer choice.

2. Boston Edison's Proposed Standard Offer Approach

a. The basic concept

As noted, this method begins with the transfer of all sunk generation costs to the access charge. This is coupled with the requirement that the utility offer to sell energy to its customers at a guaranteed price level for the 10 year transition period, which is the Standard Offer. The Standard Offer under Boston Edison's proposal is set at the expected to-go costs of the utility generation whose sunk costs have been included in the access charge. There is thus a logical consistency between the access charge and the Standard Offer. In effect, customers are "buying" the generation asset through access charge payments, and as a result are entitled to the benefit of a guaranteed energy price based on the to-go costs associated with those same units.

A key element of this approach is that customers have the right, but not the obligation, to take energy under the Standard Offer. This means that if market prices turn out to be higher than expected, customers buying energy through the Standard Offer automatically receive a benefit equal to the difference between the Standard Offer and the market price the customer would otherwise have had to pay. This differential effectively reduces the access charge paid by the customer by an amount precisely correlated with changes in market price, without the need for any actual calculation of market price to occur. If market prices remain low or decline, customers have the option to decline the Standard Offer and buy energy at the market price. In this case the customer receives no offset to the access charge, but that too is appropriate. In the circumstance where market price is less than the to-go costs of a generating unit, which by definition was the level of the Standard Offer, then the unit would have no market value and 100% of sunk costs <u>should</u> be in the access charge.

This "automatic" reflection of changes in market price are what gives the Standard Offer approach one of its main virtues - its ability to accurately charge stranded costs to customers without requiring a contentious, potentially biased administrative determination of market price.

Customers who decline the Standard Offer are not free to return to it. An open ended obligation to accept returning customers would invite gaming and would impose an untenable burden on the utility.

b. Relation of Standard Offer to the Genco and Disco

When the competitive structure is put in place, the generation and distribution functions of the utility will be functionally separated. The Disco will be required to provide the Standard Offer to all of its customers. Thus, on day 1 of choice, the Standard Offer will be the Basic Service energy package that all customers will receive, until they choose otherwise. However, the Disco has no stake in the financial benefits or detriments associated with the Standard Offer; it is simply a conduit. The Genco has the obligation to provide energy to the Disco at the Standard Offer price. The easiest way to think of the arrangement is that Disco has an all requirements contract with Genco, under which Genco is obligated to provide power at the Standard Offer price for however many of Disco's customers choose to take the Standard Offer, which price is passed through by Disco. However, Disco has no obligation to buy any more than the requirements of its Standard Offer customers. Thus Disco has no commercial incentive to promote or discourage the Standard Offer.

c. Determination of the Standed Offer Price

As noted above, the revised version of the Standard Offer is based on a forecast of the to-go costs of the utility's fleet of units. Note that this is a difference from the utility proposals filed in February, 1996. Those proposals based the Standard Offer simply on current rate levels, escalated by an agreed-to factor. Boston Edison's revised proposal unbundles rates into T&D, Access Charge, and the Standard Offer which prices the energy component only. Thus, the calculation of the Standard Offer price (based on to-go costs) connects more closely to the calculation of the Access Charge (based on sunk costs). Moreover, any performance improvements or efficiency savings that are expected to be reflected in the unit to-go costs can be negotiated into the expected price level, and thus will be automatically guaranteed to customers.

Thus, the Standard Offer approach can achieve an important mitigation element. The Standard Offer price for energy service is fixed for each year of the transition period at the time the restructuring plan is put into place, and does not change thereafter.[11] Thus, Genco has the risk that if it cannot produce power from its existing fleet (or procure it in the wholesale market) at the agreed upon price, it will suffer a loss. Genco bears this performance risk -- the Customer and Disco are guaranteed the Standard Offer price.

d. Relation of Standard Offer to Genco's Existing Fleet

There is no tie between the Standard Offer and Genco's generation fleet, once the Standard Offer is set. Genco is left with the obligation to provide whatever power is required at the stated price, but can provide that power from whatever sources make sense. Genco's incentive will thus be to produce or acquire power competitively. If any portion of the existing fleet is not competitive, Genco will lose potential profits by continuing to operate it. Genco thus appropriately bears the market and operational risk associated with the fixed Standard Offer obligation.

3. Response to Concerns Relating to the Standard Offer

In February, 1996, several utilities filed proposals with the Department calling for the use of Standard Offers. Since that time, various parties have raised concerns over certain aspects of the proposals. Some concerns are not well founded. Others we have tried to meet by developing modifications to our proposal. In this section, we identify and respond to concerns that have been raised with respect to the Standard Offer.

Concern: The Standard Offer would protect the utility's Genco from competition.

It would not, in two respects. First, while it is true that Genco starts the day with an all requirements contract with Disco, under which it receives the Standard Offer revenues from non-choosing customers that are taking Basic Service from the Disco, this is clearly not a guaranteed

[11] A negotiated settlement that established a Standard Offer price could tie this price in future years to an objective benchmark subject to efficiency gains (e.g., an RPI-X formula).

source of income. Customers can choose not to take Basic Service, and plainly they will make that choice if the market price of power is less than the Standard Offer they are getting through the Basic Service. As customers leave the Standard Offer, the requirements of Disco decrease, and Genco is left with unsold power. To sell that power, Genco will have to compete just like any other supplier in the market.

Second, the price that Genco receives under its contract is fixed at the time the Standard Offer is put in place. Thus, Genco is subject to the same performance incentive that any competitor with a fixed contract has, which it to maximize profit by cutting costs and seeking alternate, lower priced supplies.

Concern: The Standard Offer will inhibit competition because bustomers must continue to buy from Disco to obtain the benefit of the Standard Offer

Under the Standard Offer proposals filed in February, 1996, it is true that a customer would have to continue to take power from Disco in order to obtain the benefits of the Standard Offer. If the customer bought power from another supplier, he would have to leave the Standard Offer. This could be seen as having a restricting effect on the competitive market.

We believe the Standard Offer can be modified to address this issue. It can be structured to permit a customer to receive the price protection benefits even if the customer buys power from a competing supplier. This is done by recasting the Standard Offer as a contract for differences for any customer who wants a choice of supplier.

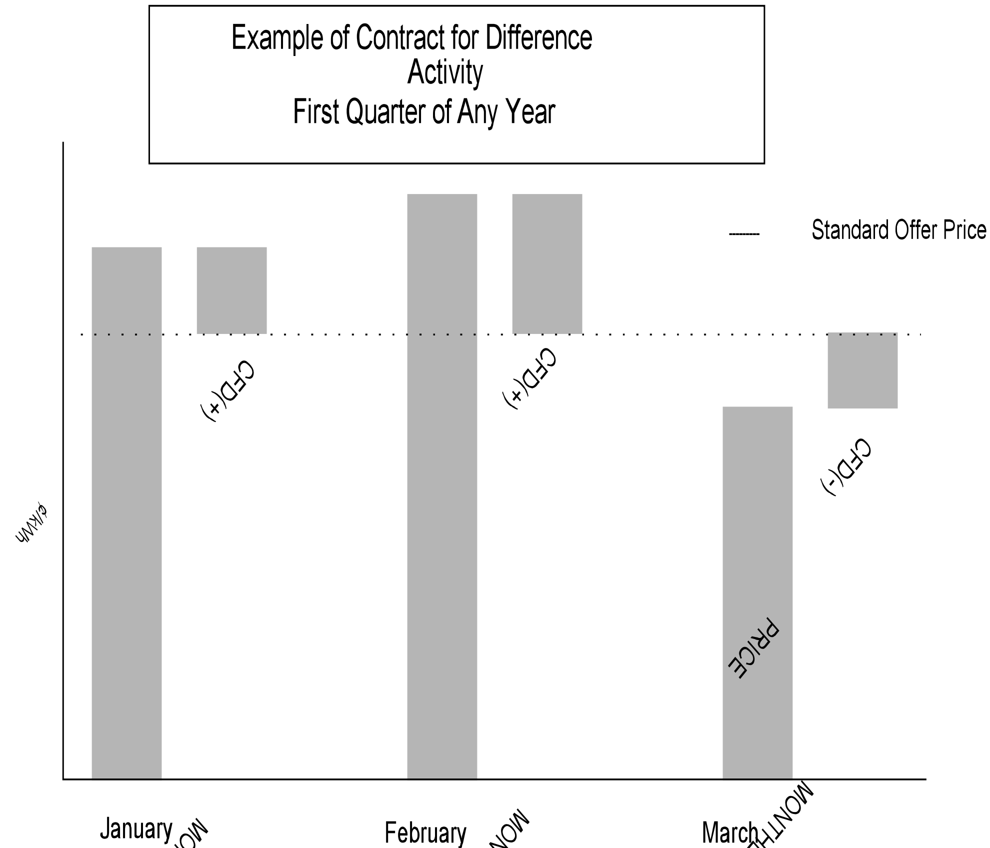
In general, a contract for differences can be described as an insurance policy against future changes in the market price of a commodity, entered into by a party who expects to buy or sell that commodity at market prices. Its purpose is to guarantee the party who purchases it price stability, irrespective of the actual fluctuations of the commodity market prices. The payments under a contract for differences thus do not cover the actual price of the commodity, only the differences between the actual market price and the agreed to base price. If, by happenstance, market prices were exactly equal to the agreed to base price over the period of the agreement, then no payments under the contract for differences would be made. In effect, the "insurance" would not be needed. On the other hand, if there are differences between the agreed to base price and actual market prices, the party who would otherwise benefit from the market price variation pays that difference to the other party. Thus, the parties are always in the position they would be in if market price equaled the agreed to base price; they have no market price risk, for the period of the agreement.

Such a vehicle can be used in the Standard Offer context. The Standard Offer is simply a fixed price contract for a commodity, in this case electricity, which is intended to guarantee price stability to both the utility and the customer. It is possible to break apart this fixed price obligation into the two underlying components described above: a varying spot market price, and a contract for differences. If the customer were to continue to contract with the utility for both halves of this agreement - that is, to buy energy at the spot price from the utility and to enter into a contract for differences with the utility - then he would end up exactly where he started, simply paying the fixed Standard Offer price. For that non-choosing customer, there would be no purpose in separating the Standard Offer into these two components.

However, unbundling the Standard Offer into these two parts provides an extremely important benefit for customer choice. A customer can choose to enter into one of these agreements with the utility - the contract for differences - while choosing to actually buy the energy - at a spot market or any other agreed to price - from a competing supplier. The customer gets to keep the insurance protection provided by the contract for differences, but can make his energy purchase from whomever he wants.

To illustrate, a customer could choose to buy energy from XYZ supplier, and choose to continue his contract for differences with Disco. Thereafter, the customer would not buy energy from or make energy payments to Disco; the payments between customer and Disco would be limited to the "insurance" differentials under the CFD. For example, if in a given hour the Standard Offer price were 3 cents per kilowatthour, and the spot market price were 4 cents per kilowatthour, the CFD would entitle the customer to a payment from Disco of the 1 cent difference, notwithstanding the fact that he was buying his energy requirements from XYZ.

The following box includes an illustration of the CFD.



1. In the months of January and February the monthly average spot market price is greater than the fixed standard offer price. Customers would receive from the Disco a credit on their monthly bill equal to the positive (+) CFD amount for each kWh consumed.

2. In the month of March customers would pay an additional charge (debit) to the Disco equal to the negative (-) CFD amount for each kWh consumed.

3. Customers purchasing energy through the Disco would see a single price for energy equal to the Standard Offer price.

4. Customers who leave the Disco and purchase energy elsewhere could elect to continue to receive the protection offered by the CFD and would have the credits (debits) applied to the remainder of their non-bypassable bill.

5. Customers could choose to decline the CFD at any time -- paying spot market prices to another supplier or to the Disco under Basic Service.

6. Other retailers could offer similar CFDs to Customers, thus increasing the choices available to customers and promoting competition in the market.

Thus, the customer would have the freedom to choose any supplier he wished, but would have an "insurance policy" from Disco that would protect him against increases in the market price. In such a scenario, the customer might want to choose XYZ supplier for any number of reasons, including unique services offered by that supplier that were unavailable or not as attractive from Disco, and he would be perfectly free to do so.

Thus, a Standard Offer approach can be modified to eliminate concerns about "tying" customers to the Disco. Customers can do nothing, and get the Standard Offer; they can buy from another supplier, but continue to take the price insurance from Disco; or they can elect to leave Disco altogether.

Concern: If Standard Offers are used, the spot market will not be sufficiently deep.

There appears to be a concern that if the Disco is buying from Genco to provide Standard Offer service, there may not be sufficient kilowatthours flowing through the spot market pool to assure that it is deep and vibrant. This concern is misplaced. There is nothing about the Standard Offer approach that must limit the number of transactions that flow through any spot market that is created. Again, the essence of the relation between Disco and Genco is that Disco has a contract to purchase all Standard Offer requirements at a defined price. This financial result can certainly be achieved if the Disco is in a "bilateral" world, and a central spot market pool does not exist; but it can also be achieved is Disco is at the other extreme in a U.K-style central pool, where 100% of the kWh are bought and sold through the pool. Under a U.K. style pool, the Disco would buy and Genco would sell all kWh through the pool, but they would enter into a contract for differences against the pool price, using the Standard Offer as the agreed upon strike price. The point is, there is nothing about the use of a Standard Offer that constrains the Department from deciding that as a matter of policy it should mandate that some or all kWh should be bought or sold through a central pool.

Concern: Use of the Standard Offer allows utilities to overcollect stranded costs.

The Revised Standard Offer will limit utilities from "over-recovering" stranded costs.

Sunk costs included in the access charge are used as starting point to calculate stranded costs and provide a ceiling on recovery. If market prices increase significantly over time, then customers may obtain the benefit of price protection through credits to the access charge via the retail CFD mechanism. On the other hand, if market prices decrease significantly, then it was appropriate to include the sunk costs in the access charge initially. This mechanism will avoid customers paying twice if market prices rise and will provide the appropriate market-based operating incentives for utilities while maximizing customer choice.

Concern: Under the Standard Offer there is no incentive to divest.

A Standard Offer can incorporate incentives that will encourage utility divestiture of generating assets. However, treatment of divestiture incentives must be compatible with the basic *quid pro quo* of the one-sided Genco obligation to supply at avoidable to-go costs. As discussed above, the standard offer results in price protection and allows customers to obtain the market value of existing assets over the transition period. A sale of a generating asset from the utility portfolio would eliminate the premise on which the Standard Offer was based; that is, that power could be obtained at the to go cost of that unit. A similar result occurs in the case of the shut down of uneconomic assets. The Company has looked at the incentive issues relating to divestiture and shut down and believes there may be a number of alternative treatments that would be both efficient and equitable. We outline two alternatives below as the basis for further settlement discussions.

Under the first alternative, sales and shutdowns of assets are reflected in both the undepreciated value of the regulatory asset and the standard offer. For example, suppose an asset with a net book value of $50 Million were sold for $100 Million (with no contract back). The sale proceeds of $100 Million would be credited against the regulatory asset to reduce the size of the access charge going forward, thus reducing rates to customers. On the other side of the ledger, the avoidable to-go costs associated with the unit sold would be removed from the standard offer -- in effect, replaced with spot market power. Incentives for utility divestiture of generation could be overlaid on this mechanism.

Under the second alternative, the Standard Offer will stay in place through the ten year transition period regardless of whether units are sold or retired. Under this alternative no adjustments would be made to the regulatory asset or to the standard offer for units closed by the utility. Sales of units would be accompanied by contracts back that mirrored the expected recovery of the sunk costs through access charge and the expected benefit from the standard offer.

Concern: The Standard Offer does not address residual value at end of term.

Although the standard offer allows customers to obtain the market value of generating assets <u>during the transition period</u>, the residual market value of assets at the end of the transition must be addressed separately. If generation assets are divested during the transition period, the residual value will be incorporated in the purchase price. However, assets that remain undivested may still have some residual market value. The Company's Standard Offer approach would recognize the need for some method to value those assets at the end of the transition period. Alternatives might include a voluntary auction in year ten, a valuation formula based on the forward price for power at the end of year ten, or a contemporaneous administrative determination of value. The incentives that result from this "end-game" valuation would need to be carefully structured so as not to interfere with the incentives established during the transition period.

4. Other Alternatives to the Department's Approach

In addition to the Standard Offer outlined above, the Company believes that two other alternatives merit consideration by the Department. Each of these is discussed briefly below.

a. Administrative determination with a tight price true-up

The Department's proposal could be modified to allow a one-time determination of stranded costs subject to a tight true-up for deviations of actual market prices from forecast market prices. The gaming incentives discussed earlier would still exist, but would be tempered by an equitable sharing of market price forecast risk. Basic Service could be offered at the administrative determination of the forward market price. The true-up to actual market prices would be used to adjust the access charge. This type of proposal would still have strong mitigation incentives without using a wide deadband.

b. Forward contract auction

The Department's proposal could be modified to allow an open season coupled with a one-time (or annual) RFQ for wholesale sales by the utility for the remainder of the transition period. The utility would sell generation under contract to bidders equivalent to the load of customers choosing other suppliers. The average market price of the forward contract sold by the utility would lock in the stranded cost valuation (and access charge) for customers exiting the system. Basic Service could be offered to customers remaining on the system at the RFQ determination of the forward market price.

C. Above Market Purchased Power Costs

We have two concerns in this area. First, the Department's proposed rules create a significant concern regarding the recovery of stranded costs associated with above market purchased power costs. Second, the Department needs to create a structure which gives utilities some means of negotiating reductions of future costs under purchased power contracts.

As to the first concern, we see a potential shortfall of stranded cost recovery that, depending upon market prices, could approach a billion dollars, which would lie essentially outside of our control to mitigate or manage. This occurs because the Department has stated in its proposed rules that in no case should stranded costs be collected for more than ten years. This is flatly inconsistent with the stated principle, which is to provide utilities with a reasonable opportunity to recover their stranded costs. While ten years may be an appropriate amount of time in which to recover some categories of stranded costs, clearly it is not so for costs associated with long term purchased power contracts. Boston Edison feels strongly that, even when accounting for the utmost mitigation possible, ten years does not afford us with a reasonable opportunity to collect our stranded costs associated with long term power purchases, assuming rates are restricted to current levels. We urge the Department to reconsider its proposed recovery mechanism for this portion of stranded costs and to adopt an alternative that allows for collection of above market purchased power costs beyond the proposed ten year recovery period.

Many of the contracts that Boston Edison entered into in the past extend far beyond the proposed ten year recovery period, the last not expiring until the year 2019. These contracts were entered into for such long terms with the sole intention of securing lower prices and, hence, reducing costs for consumers. The costs associated with these contracts were incurred as prudently as were the costs for our own sources of power generation. The Department approved the terms and lengths of all contracts in question and should allow full recovery of the non-mitigable portion of these contracts without limiting that recovery to an arbitrarily chosen ten year time span.

Purchased power costs represent the single most significant portion of Boston Edison's estimated total stranded costs. Purchased power costs that are estimated to be above future market prices comprise approximately one half of our total Access Charge throughout the proposed ten year recovery period. Depending on the market price for electricity, Boston Edison could be at risk for anywhere between $0 to as much as $1 billion for above market costs for purchased power beyond 2007. To deny Boston Edison the opportunity to recover such a large piece of its stranded investment by fixing the recovery period to only ten years, while capping rates, would be confiscatory.

One alternative which would allow for the full and fair recovery of these costs would be to allow rates to increase during the 10 year period to accommodate the acceleration of the purchased power costs into the 10 year window.[12] A second alternative to avoid this burdensome increase in rates is to extend the recovery period for purchased power beyond 2007 by just a few

[12] Obviously this would require either some estimate of the above market portion of purchased power costs during the post-2007 period, or some actual sale, buyout, or other disposition of the post-2007 power purchase obligation. We would be wary of the market price estimation process, for all of the reasons discussed previously. While not opposed to a sale or buyout which would fix the obligation, we are yet to see how this could or would actually occur to anyone's advantage. For example, assuming the contracts were assignable, etc., by our estimate we could possibly sell all of our existing power purchase contracts by paying some X hundred million dollars. The element of competition might reduce that amount somewhat, however, we would still have the problem of how to make that payment and accommodate near term rate objectives.

years. By simply maintaining the declining trend of our total estimated Access Charge, our remaining estimated stranded costs due to above market purchased power can be recovered in an additional two to five years, depending on market price. In this way the recovery period is extended for only a short time, yet stranded cost charges are still gradually phased out. Moreover, consumers are spared excessive rate increases and utilities are afforded a reasonable opportunity to recover their stranded costs without the need to collect those costs through the final expiration of all its contracts. A final alternative is the one suggested by the Company and others in their initial comments, i.e., extend the collection period beyond the 10 year window to coincide with the previously approved terms of these contracts.

The Department further states in its proposed rules that utilities should maximize mitigation and seek to reduce the level of stranded costs, e.g., through renegotiation of power purchase contracts. While the Department has set up incentives for utilities to mitigate their purchased power expenses through contract renegotiation, there are no such incentives for NUGs to do the same. We believe utilities and NUGs should have equal incentives to renegotiate contracts that exceed market prices whenever practicable. One alternative is a shared savings arrangement where all parties to a contract can benefit from a renegotiation of terms. Any savings realized due to renegotiation or buy-outs of contracts should be shared among customers, utilities, and NUGs.

D. Nuclear Decommissioning Costs

The recovery of nuclear decommissioning costs as a part of stranded cost recovery has been a consistent element in the Department's previous orders and in virtually all restructuring proposals and comments. In addition, financial assurance for decommissioning costs has been a significant and continuing concern of the U. S. Nuclear Regulatory Commission. See 10 CFR 50.75; NRC Advance Notice of Proposed Rulemaking on Decommissioning Financial Assurance Requirements, 61 Fed. Reg. 15427, April 15,1996.

We do not believe there is any question that the costs of nuclear decommissioning are "committed" as a result of existing ownership and operation of nuclear generating facilities. Unfortunately the amount of those costs is highly uncertain--affected largely by the question of when spent nuclear fuel will be allowed to leave existing sites for purposes either of interim offsite storage or permanent disposal. In the absence of some enforceable commitment from the Department of Energy on the latter issue, all estimates of decommissioning costs must assume some period of post shutdown costs. Such costs are not ameliorated, even by immediate or premature shutdown, since the already onsite fuel must be managed safely for essentially the same period of time before applicable safety and security systems can be discontinued and the site returned to unrestricted use.

In this context the Department's proposed rules as related to the estimation of "embedded" costs of nuclear decommissioning and the recovery of all of those costs during the current plant operating license appear unwise and unworkable. They raise the very significant question from the NRC's perspective regarding assurance that all decommissioning costs will be provided for, if current estimates are not sufficient. They put an extreme, if not impossible, premium upon the accuracy of decommissioning estimates based upon uncontrollable events. In effect they create an incentive to game the estimates.

Accordingly, we see little alternative to leaving the ultimate recovery of decommissioning costs on a cost of service basis, with appropriate true-ups after such costs are incurred. In terms of the Department's proposed rules we propose two changes:

(1) That the decommissioning cost element in 220 CMR 11.03 be isolated from the other "embedded" costs and periodically adjusted (not more than every 2 years nor less than every 5 years) without the bandwidth provision. As presently drafted, 220 CMR 11.03(4)(3) contains large bandwidths that would motivate a utility to include additional contingencies in the decommissioning cost estimate to account for the many uncertainties inherent in estimating complex activities that will take place many years in the future.

(2) That a provision be added to recover additional decommissioning costs should there be a post-shutdown change to the decommissioning costs that could not have been anticipated or controlled by the utility. Again, without such a provision, a utility would be motivated to include additional contingency to its decommissioning cost estimate to allow for such possibilities. Clearly such a provision should work in parallel with an obligation to refund any excess costs, should such eventuality occur.

Should there be special treatment for nuclear generation?

The Department recognizes that "[n]uclear units have unique costs and uncertainties associated with their operation, reliability, safety, decommissioning, and issues related to liability." DPU 96-100, p.58. Based upon this recognition, the Department asks a series of questions directed to whether some special treatment may be appropriate for the recovery of stranded costs associated with nuclear units. In this section we will briefly review those questions and offer several suggestions.

The Department first asks whether there are special considerations regarding nuclear units that require different or distinct treatment from other types of generation. Our answer is that there clearly are such special considerations. The primary example of this is decommissioning costs, which we have discussed at some length in the previous section. Furthermore, decommissioning clearly requires distinct treatment for stranded cost recovery.

Other types of special considerations related to nuclear units, such as safety, reliability, base-load operation, marketability and liability, are alluded to by the Department in their discussion or in other questions. In isolation, these considerations are clearly different for nuclear and require careful management and attention. However, whether these other considerations, apart from decommissioning, <u>require</u> different stranded cost treatment from other types of generation is largely an issue of how stranded costs are treated for these other generation types. If sunk generation cost recovery is handled through a standard offer approach as we recommend, then we believe it quite possible that nuclear generation could be treated very similarly to other types of generation. On the other hand, if generation divestiture is required or some type of market test is necessary, then we believe it very likely that some separate approach may be required for nuclear generation.

This leads to the Department's second question which concerns market considerations for nuclear units. Nuclear units are clearly less marketable than other types of generation. Of the three reasons suggested in the question, we believe that "liability concerns" is a more significant factor than either public perception or operating costs. While the costs, either capital or operating, are not inconsiderable, the primary issues would relate to the uncertainties in those costs. Another significant factor is the requirement for NRC approval. NRC regulations as related to financial assurance for safe operation and as related to decommissioning costs are built upon a premise of cost of service economic regulation. See, e.g., NRC Advance Notice of Proposed Rulemaking on Decommissioning Financial Assurance Requirements, 61 Fed. Reg. 15427, April 15, 1996. We believe it would be quite difficult to arrange a transfer of a nuclear operating license to a non-regulated entity without extensive NRC review. This leads us to suggest that a divestiture approach is particularly unlikely to be workable for nuclear generation assets.

The Department's third question concerns performance based ratemaking for nuclear generation. Generally we think this is an acceptable approach, which we think is embodied in our standard offer proposal. The Department notes that Pilgrim is already subject to a form of performance based ratemaking, so the issue is clearly not one where it is impossible to devise a solution. In fact, we think that the history of performance based regulation of Pilgrim has largely been a success as measured through improved operation, availability and cost. The current Pilgrim NPAC is scheduled to continue through 1999, however we would expect this to be superseded by the standard offer once agreed upon and implemented. Once the standard offer is in place, it should be noted that there is no longer any actual tie to the operation of particular generating units. The operation of Pilgrim, as with any other generation, fossil or nuclear, would purely be a matter of its own going forward performance and costs versus the market. If Pilgrim is an economic source of generation, as we believe, then customers will receive that benefit as embodied in the standard offer. If Pilgrim is not perceived as economic, customers will be free to not accept the standard offer and purchase power elsewhere. If Pilgrim is in fact uneconomic, then we will have the economic incentive to shut it down.

The Department's fourth question concerns safety. We clearly agree that safety is paramount and we fully support the NRC in its responsibility to assure safe operation. Contrary, however, to the implication that safety and economics are in opposition to one another, it is our observation that the safest plants are often the most economic. Furthermore unsafe operation leads inevitably to no operation, which is clearly the least economic course of all. We think that competition should act as a spur to more economic operation, or perhaps lead to a decision to shut down uneconomic generation, but all parties should use care to make certain that safety is not compromised.

The Department's final question asks for possible recovery mechanisms for nuclear stranded costs. As noted previously, we believe that full recovery of decommissioning costs is required (including the costs of any premature decommissioning costs resulting from early shutdown), no matter what form the rest of the proposal. For sunk generation costs, we believe that a standard offer approach for all generation would be the preferred mechanism, which in effect would be no special treatment for nuclear generation. If some form of generation divestiture is required, then we would suggest that nuclear generation be excepted from such requirement. In that case we might recommend examining some of the proposals being developed for the California nuclear utilities which generally involve accelerated nuclear depreciation in exchange for an administratively determined set of rates during the accelerated depreciation period. We have not attempted to structure such a proposal for Pilgrim, apart from our standard offer approach for all generation.

To summarize our views on this issue, we definitely agree that nuclear stranded costs present a number of special issues. Apart from decommissioning, however, one of the virtues of our standard offer approach is that nuclear plants can be handled conceptually much like any other generation, and decisions to operate or shut down a particular plant can be made on the basis of its performance versus the market, rather than based on non-market considerations.

IV. SERVING THE CUSTOMER

In our initial filing we noted that, while the restructuring debate was being carried on principally by people intimately familiar with the economic, regulatory and technological aspects of the electric power industry, it is the customers who will have to bear the burden of change. Regardless of the restructuring model adopted by the Department, it will succeed if, and only if, the change and the need for it makes sense. It must make sense not only to the large commercial and industrial customers, many of whom are actively participating in this debate, but also the millions of residential and small commercial customers, whom we believe are rightfully skeptical of why and how restructuring will be good for them.

While some may complain that prices are too high, there is not a groundswell of sentiment that the electric power industry is broken and needs to be fixed. Most customers are content to receive bundled electric service from a local supplier. This will change with restructuring as the customer will be required to take on and adapt to an active, rather than passive, role in their electricity purchases. This is a dramatic change for the average customer who lacks information and understanding of what is occurring so as to make an informed decision. Customers are concerned about the price of their electricity. However, customers are also interested in convenience, certainty of prices and the reliability of their electric service. Boston Edison continues to remind the parties to this restructuring process should be about customers and how to meet their needs.[13]

Our concern for the disruptive impact restructuring will have on customers led us to propose a phased-in approach to restructuring. We are pleased the Department agreed with us and adopted our Phase 1 of E-Plan for state-wide implementation in 1997. The Department went further this year by setting up a customer education task force which is designed to develop, on a coordinated basis, customer education needs and tools. We commend the Department for taking

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[13] Simplicity will be essential in the new relationships being developed between customers and utilities in the restructured industry. We must keep in mind that in the foreseeable future the competitive portion of the customer's bill will be for generation services, which for a customer using 500kWh/month at a price of $.03/kWh, accounts for only $15.00 of the total bill. We should not be inventing a system which is so complex that it will engender unnecessary and unwanted communications simply to explain the bill.

these steps and believe we must continue to focus on the customer benefits and customer service aspects of industry restructuring.

Restructuring presents all parties with a unique opportunity to simplify and reinvent the industry. With that in mind, our comments here address some key customer service issues raised by the draft rulemaking: adoption of appropriate pricing models for newly unbundled distribution services, introducing a customer friendly energy pricing options and the multiple roles of the distribution company in the new market relationships and in providing energy efficiency services.

A. Distribution Rate Model

The Department has focused much of its effort on creating the new market structure to support the development of competitive industry components. We recognize the importance and need for this effort, however, we strongly recommend that the Department look at the entire customer impact of the changes and not simply at the competitive market structure changes in this process. A key concern arises because the vertically integrated business has been at least functionally unbundled and each businesses pricing of their service(s) should reflect the cost causation for that business. The current tariff structure (low fixed and high variable) reflects the generation component of the industry. In the new model, each business is likely to be priced differently. For example, transmission may be priced on a megawatt mile model or a flat usage fee, while distribution, which is largely driven by high fixed infrastructure costs rather than by incremental customers or usage is appropriately priced with larger fixed and smaller variable components.

Restructuring will result in an entirely new approach to customer billing and will provide a unique opportunity to simplify and make more efficient the customer's relationship with the utility. As we noted in our initial filing, we envision the customer receiving one bill with two very distinct services - energy and delivery. The providers of those services will be different entities. All parties agree that the energy portion of the bill will be set either by the spot market or by some contractual arrangement between the energy provider and the customer, which could include a standard offer. What the Department needs to focus on in its rules is that the delivery rates need to reflect the new competitive realities. To that end the Department needs to allow distribution companies the flexibility to utilize new rate designs.

Traditional rate design utilizes economic principles to develop appropriate pricing signals for customers. In the past, rates were based on the marginal cost of generation to establish the pricing signal and then were trued up through one of the rate components to recover embedded costs, which are typically higher than marginal costs. With the introduction of competition, customers will see the unbundled price for each of the services provided to them.

The principles of economic efficiency become more important as we move to restructuring. Tariff design must reflect the fact that investment in network services is more fixed than it is variable by consumption. For example, investment in metering, billing systems, customer response systems, are one-time investments with very little incremental cost to serve existing customers. The distribution system similarly reflects currently installed capability or more fixed than variable costs. Any additional investment is typically split between reliability and load growth. Therefore our approach to determining pricing requires a shift away from predominantly variable pricing to higher fixed charges. If fixed costs are inappropriately included in the variable component of the bill, this could result in uneconomic customer decisions by encouraging customers to self-generate, consume more expensive fuels and, if in the bypassable energy component, switch suppliers.

Boston Edison believes that simplicity in rates may outweigh all other factors for our customers. In fact, in the future we envision a bill where you pay a high fixed charge for basic monthly service, with relatively small variable components for usage, much like the cable television or telephone delivery industry. Such a charge would reflect the fixed, as opposed to variable nature of most distribution investment and would ensure that stranded costs were non-bypassable.

B. Customer Friendly Energy Pricing Options

The proposed rules provide for the distribution company to be the supplier of last choice for energy. The proposal assumes those “non-choosing” customers should be required to take basic service at the spot price for energy. Since there are likely, in many parties’ opinions, to be many more “non-choosing” customers at the outset than customers who switch suppliers, there will be many customers who will be dissatisfied with the inability to: 1) choose the old distribution company, and 2) choose alternative payment mechanisms. Many parties are assuming that a decision not to enter the new supplier market means the customer is just ambivalent about reform. However, in our opinion, a customer who chooses not to enter the market may in fact be satisfied with the distribution company and is in fact choosing to wait and see how the new market evolves. The new system should not force customers to choose on day one if they do not want to choose. The draft rules make the energy service passed through by the distribution company so unattractive an alternative that customers may be forced to participate in a market they are not ready or willing to accept on that date. Flexibility is the key. Customers should be able to choose when they want to change and how they take their pricing.

Some examples of customer choices include the ability to offer budget billing to smooth out the volatility of spot market. This service results in the customer paying the same amount on an annual basis but the amount is smoothed over the twelve months. The current proposed rules indicate that while the distribution company must maintain its social responsibilities for low income and conservation. However, it appears that with the basic service spot price approach will not be allowed, except for customers who are in arrears on their payments, to offer billing options to distribution company customers. Our understanding is that only the competitive energy service providers will be able to offer billing options to the end user. This is unfair to the customer who is satisfied with their current relationship. The Department should include flexibility in the final rules to allow distribution companies to offer alternatives to the hourly prices for energy in an effort to provide customers a service they want without paying a fee to a retail company.

We have interviewed our customers to determine their needs for services. Our discussions have included each customer segment. In addition, we have asked our customers for a description of the best service provider they deal with and to identify the characteristics that make them best in class. The findings are that while the price of a service is a key component in a customers purchase decision for electricity and other products, many other key characteristics also matter in their decision. Two primary factors customers continually cite with a high importance rating when choosing a supplier include: 1) the ability to choose a products' characteristics (price, features), and 2) the services offered in association with the product (reliability, billing options, accuracy of billing, account support, ease of interaction with company, response to emergency calls). Customers have also indicated to us that price certainty is of importance to them so they can plan their purchases and budgets (both residential and business customers).

As the draft rules are structured, the distribution company will be restricted from offering these important features to customers who choose to remain. In addition, unless the standard offer is adopted, customers will be forced to change to a supplier who may offer certainty in their pricing rather than continue their relationship with the distribution company. The rules should be changed to provide the distribution company more flexibility within the customer base it retains.

Offering distribution companies this flexibility should not deter customers from choosing alternative suppliers. Once the market is established in 1998, there will be a wide variety and large numbers of marketing companies (power marketers, load aggregators etc.) actively seeking new customers for their services. Customers, individually and in groups, will have easy access and in fact may be approached frequently to change suppliers and service companies. Although the position of many parties is to maintain the distribution company as simply one who delivers, the draft rules maintains some customer relationships through billing and social obligations. We believe the rules should be flexible enough to allow the distribution company to offer to those customers who remain with them, options in their service packages (summary bills, budget billing).

C. New Market Relationships for Distribution Companies

Under the draft rules, distribution companies become the provider for customers who do not elect a new supplier, customers whose supplier is unable to provide service for, and customers who require backup service. Distribution companies also provide the billing service and respond to customer inquiries about bills. If distribution is responsible, employees will require extensive system support and knowledge of the various competitive power company offerings. More importantly, the distribution company becomes the business that bears the responsibility to serve customers when all else has gone wrong.

The distribution company takes on many roles in the draft rule which are burdensome and provide all the downside risk. A key example is the discussion where a supplier notifies the distribution company that it can not supply the customer and then the distribution company notifies the customer. Why should the distribution company be the bearer of such news? To make the proposal even less equitable, the performance based ratemaking proposal in the draft rules provides the utility with only penalties and with no opportunity to earn a reward for excellent performance. The final rules should include some stretch factors which provide the distribution company the opportunity to improve service and earn a reward. The Department should take a carrot and stick approach rather than a penalty approach in isolation.

Finally, the product's features will drive each customer's decision in the competitive marketplace. We urge the Department to keep customer needs and satisfaction uppermost in the development of the rules. We strongly support flexibility for all new business lines to address these issues appropriately.

D. Energy Efficiency Services

Boston Edison is in general agreement and supports the Department's goal of free market competition in energy efficiency services. We agree with the Department's proposal calling for a transition to, rather that an abrupt end of, traditional electric company sponsored DSM. We propose that a process similar to the current IRM process serve as the transitional tool for all markets, especially the commercial/industrial sectors. Throughout the transition we are committed to offering meaningful energy efficiency education programs especially to small business and residential customers. In addition, we are currently investigating low interest financing options for energy efficient measures with various financial institutions.

The Company supports a gradual transition to a non-regulated marketplace but proposes a period shorter than 5 years. The non-regulated retail companies will aggressively pursue the profitable opportunities for energy efficiency during the transition period. In the regulated market every effort should be made to eliminate and streamline administrative tasks and the regulatory oversight process. We believe that efficiencies can be gained without jeopardizing program effectiveness. We are committed to serving the residential market and will not abandon programs to these customers. As for budget levels, the Company will continue to reduce its program expenditures in the regulated arena annually throughout the transition period. Boston Edison will always be committed to energy efficiency, environmental protection and the affordability of energy efficiency measures to all consumers.

VI. CONCLUSION

We have two primary messages in these comments. One is that we should continue to make progress, by remaining flexible and not forcing premature commitments to positions that cannot be adhered to. We believe that flexibility will lead to settlements, whereas some proposed rules may only lead to litigation. The second message is to remain focused on the customers. Rules relating to basic service and distribution service require customer input that has not yet been received.

We look forward to continue to work with the Department, customers and all affected parties as we continue to move down this road to industry restructuring.

Respectfully submitted

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By its attorney

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